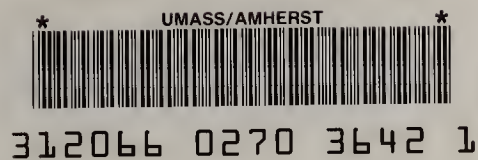


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POWER CHOICE

**A Plan to Deregulate Elements of the Electric Industry
in Massachusetts**

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**Division of Energy Resources
of the
Commonwealth of Massachusetts**

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February 13, 1996

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I. EXECUTIVE SUMMARY

In August of 1995, the Massachusetts Department of Public Utilities issued Order 95-30 declaring its intention to provide retail electricity customers with choice of supplier and move electric companies toward separation of their generation, transmission and distribution functions. The Order directed three electric companies to develop plans to restructure their operations and file them with the Department by February 16, 1996.

The Massachusetts Division of Energy Resources (DOER) herein offers **Power Choice**, its own version of a generic electric utility restructuring plan. DOER files this plan to clarify the approach DOER believes best meets the Department's guidance on restructuring and to provide a basis for agreement among all parties on how best to serve the needs of retail electricity customers.

Section II of **Power Choice** presents the core elements of the plan, first in the form of a vision of a restructured electric industry and then the steps that must be taken to accomplish an orderly and expeditious transition. In the future, each of the presently regulated electric companies will be separated into unregulated generation companies and regulated distribution companies. Any qualified generator may offer electricity for sale, and a variety of companies vie to provide customers with choices of power and related services. Over a three year period, electric companies voluntarily divest themselves of generation assets and retail functions through sale or spin off to new companies of their creation.

An Independent System Operator (ISO) operates the regional transmission system and provides open access to that system at comparable tariffs to all users. A separate and voluntary Power Exchange facilitates electricity trading on a regional basis through a spot market. The Distribution Company ensures that all customers receive electric service, administers low-income and consumer protection programs and provides electricity to customers who do not receive power from a competitive supplier. It recovers its costs through regulated rates based on the quality of service it provides.

Environmental improvement continues through reduced emissions at existing power plants, and conservation and renewable energy programs are maintained by Distribution Companies through the transition period. Electric companies use a market-based valuation process for identifying and mitigating stranded costs in a way that is fair to both the companies and consumers. Stranded costs are recovered by Distribution Companies through the transition process in charges approved by the Department.

Section III of **Power Choice** details how this plan meets the requirements of the Department's August, 1995 Order. Finally, the details of a performance-based rate structure for Distribution Companies is presented in Section V.

II. THE PLAN: **Power Choice**

The Department has directed each electric company to file "a plan for moving from the current regulated industry structure to a competitive generation market and to increased customer choice". D.P.U. 95-30 at 47. While not an electric company, the DOER hereby presents a restructuring plan, **Power Choice**, for consideration by the Department, electric companies, and other parties.

This section presents the core elements of a strategy that restructures the electric industry in Massachusetts in an orderly, expeditious, and straightforward manner. The elements are presented in summary form. Details are left to later sections of this filing.

Power Choice is presented in two parts: first, our vision of the industry is summarized as it should be structured when the transition process is complete; second, the transition process needed to achieve a fully restructured electric industry is discussed.

A. VISION OF THE INDUSTRY

1. New Corporate Structure for All Electric Companies

Each electric company fully separates all of its competitive generation and retail sales functions, so that the former electric company ultimately provides only two primary services directly to its customers: Distribution Service and Basic Service. Distribution Service is the local wires service needed to deliver electricity from the transmission network to the final consumer. Basic Service is electricity services provided to customers who have not chosen a generation supplier. The company that provides these two services is called the Distribution Company.¹

2. Customer Choice of Suppliers

To assure that all customers have an unimpeded choice of suppliers, each Distribution Company that provides Distribution Service establishes:

- a. procedures for customers to choose their supplier of generation service;
- b. procedures to assure that Distribution Service is available to all customers and suppliers on a non-discriminatory basis, including assurance that interconnection standards and wires upgrade requirements and charges are necessary, reasonable and non-discriminatory;
- c. a Distribution Service tariff that is available to all customers and to all suppliers;
- d. procedures to track energy and power flows within the company's distribution system for purposes of settlement and balancing, and to appropriately bill each customer (or their supplier, if authorized by the customer) for Distribution Service; and

¹The term "Distribution Company" is used throughout this Plan to refer to the regulated monopoly electric company after it has spun off or divested itself of its generation and competitive retail functions.

- e. average load profiles provided on a timely basis to customers and suppliers for purposes of allocating energy and load between customers and suppliers, so as to enable customer choice of a supplier without requiring the installation of any metering equipment beyond that in place today.

3. Regional Wholesale Market Structure

The New England transmission grid is operated as an integrated system by the New England Independent System Operator (ISO), a new corporate entity. A New England Power Exchange (PX), a separate entity, conducts an open spot market for electricity, determines a spot market price, and settles any financial imbalances between buyers and sellers. These institutions operate under the following arrangements:

- a. Distribution Companies which own transmission facilities lease them to the ISO.
- b. The ISO and the PX are each owned and governed in a manner which insures they are independent, that is, they are not controlled by one or more groups of buyers or sellers of generation or transmission.
- c. The structure and functioning of both organizations is to be designed to facilitate full and fair competition in both wholesale and retail markets.
- d. The ISO has an obligation to maintain the reliability of the regional transmission grid, and to provide transmission service, subject to reliability and technical constraints, to any generation supplier who requires it.
- e. The ISO provides transmission and ancillary services directly to generators, retailers, customers and other market participants that seek such service, and charges them accordingly. Therefore, retail customers are generally charged for transmission service by the supplier(s) they have chosen for their generation service.

- f. The PX does not have an exclusive right to provide its functions, and no non-utility market participant is required to participate in the PX spot market.

4. Universal Service/Consumer Protection

The Distribution Company provides connection and Distribution Services to any customer in its geographic service area seeking Distribution Service. Consumer protections, including shut-off protections, are administered by the Distribution Company.

5. Basic Generation Service for All Customers

To assure that all customers continue to receive electricity if they have not designated a competitive supplier or if their designated supplier fails to deliver, each Distribution Company administers Basic Service using the following:

- a. a Basic Service tariff that prices electricity supply to reflect the hourly New England spot market price, as posted by the New England Power Exchange (see section II.B.3 below) or as otherwise authorized by the Department, using the load profiles described above for customers without hourly meters; and
- b. a procedure to assure that Basic Service is provided to all customers who have not authorized the Distribution Company to assign a supplier to them, or who for any reason are not receiving all of their electric load requirement from another supplier;

Distribution Companies are prohibited from providing services that have been defined by the Department as Competitive Generation or Retail Services.

6. Environmental Improvement

Not later than December of 1999, electric utilities reduce air emissions from their oil and coal-fired power plants to levels which, on a "portfolio" basis (as specified in Section II.A.6.a), approximate the emission limits for new oil and coal-fired plants in Massachusetts. Electric utilities also achieve additional reductions in emissions of greenhouse gases and air toxics.

B. THE TRANSITION

The transition steps set forth below are based on the assumption that electric industry restructuring should proceed in an orderly, expeditious, and systematic manner. Those issues that are completely within the Department's authority to resolve should be distinguished from those issues that require legislative action and/or cooperation with other States in the region or with the Federal government. The steps also are based on the conviction that restructuring in Massachusetts need not be delayed pending actions at the Federal level or in other States which may be desirable but are not prerequisite to restructuring in Massachusetts.

The steps contemplate that electric companies and stakeholders will undertake actions that implement restructuring under the separate jurisdictions of the Department, the Massachusetts Legislature, the FERC, and New England-wide bodies concerned with reliability of electricity supplies in the region. Some of the actions can and should be conducted in parallel (e.g., the Department could require electric companies to unbundle retail rates while, at the same time, encouraging others to modify transmission and power pool arrangements). Nevertheless, the order of the actions presented here offers a logical and practical progression of events.

1. Department Rulemaking

On or about July of 1996, the Department issues generic rules which clarify restructuring actions each electric company within its jurisdiction must take. The rules address the market structure, the methodology for stranded asset valuation and recovery, DSM program delivery, incentive-based rate design, pilot programs, and other generic issues.

2. Independent Transmission System Operator

Not later than January of 1997, an Independent System Operator ("ISO") commences operation providing open access for all generators to the transmission system.

3. New England Power Exchange

Concurrent with the development of the ISO, a voluntary association of buyers and sellers of electricity establishes a market which facilitates electricity trading on a New England-wide basis. If in the judgment of the Department, the New England Power Pool has not been reformed to provide an independent Power Exchange by January of 1997, the Department could require electric companies to establish and

participate in such an exchange, to serve at least interested buyers and sellers of generation in Massachusetts.

4. Pilot Programs

Beginning not later than January 1, 1997, each Distribution Company enrolls at least ten percent of each class in a program of retail choice of supplier, consistent with the Department's generic rules.

5. Rate Cases

Upon issuance of final rules by the Department, the Distribution Companies file rate cases on a staggered basis, which unbundle rates, deregulate generation pricing, apply incentive regulation to the pricing of Distribution Service, and establish for each company any Competition Transition Charge authorized by the Department. Final rate orders are issued by the Department within the six month statutory suspension period, and all jurisdictional electric companies have received such Orders by July of 1997.

6. Deregulation of Generation Pricing

At the conclusion of each company's rate case, expected to occur between January and July of 1997, the ratepayers' obligation to pay future generation costs of the utility's power plants is terminated. Utilities must earn revenue to cover their generating costs through competitive pricing at the wholesale level. Retail customers pay regulated rates for Distribution Service and for any transition charges, and are charged spot market prices for Basic Service generation.

7. Customer Education

Beginning not later than July of 1997 and continuing through July of 1998, Distribution Companies inform customers through a comprehensive campaign of the opportunity to select a retail supplier of generation, and explain how customers can exercise their right to choose a retail supplier, including the right to join with others to buy as a group.

8. Marketing by Retailers

Retail suppliers of generation can be expected to inform customers of the services they can provide if chosen, which supplements standard information provided to customers by the Distribution Company.

9. Introduction of Direct Retail Access

Not later than January of 1998, all customers of all companies are free to purchase power from any qualified generator or retailer. Companies implement rates approved in rate cases and commence collection of the Competition Transition Charge for recovery of estimated stranded costs as approved by the Department. Each electric company introduces unbundled Distribution Service as soon as its rate case has been completed by the Department, and any necessary FERC approval has been received for any FERC-jurisdictional components in the Distribution Service tariff.

10. Separation of the Retail Function

Not later than January of 1998, electric companies sell or spin off their retail functions to new, separately owned, unregulated companies. Such functions include their field sales force, service packages, and general and administrative operations not directly involved in distribution functions.

11. Interim Recovery of Stranded Costs

Upon completion of individual rate cases in 1997, Distribution Companies collect a non-bypassable, non-discriminatory Competition Transition Charge (transition charge) from all customers in a manner established by the Department to provide each company with an appropriate revenue stream for recovery of its estimated stranded costs. Estimates of stranded costs are made based on Department review of information presented by all interested parties on the likely outcome for each company of the application of the methodology set forth in section 12 below.

12. Stranded Costs

Over a three year period from January of 1998 through December of 2000, each electric company conducts a market-based valuation of all non-T&D assets. This is accomplished by an auction or by a spin-off to an independently-owned company. Upon completion of this market valuation process, the companies net the market value of any assets that are above book value against the market value of those that are below book value.

To further mitigate stranded costs, utilities and suppliers receive financial incentives to renegotiate or buy out Power Sales Agreements (PSAs). For those PSAs which are not bought out, the rights to such power are auctioned. The proceeds from those auctions are netted against the remaining contract obligations.

Not later than December of 2001, the companies receive an adjustment in the transition charge from the Department reflecting the actual revenues derived from the sale or spin-off of their non-T&D assets, adjusted to account for revenues already collected through the interim Competition Transition Charge.

13. Regulation of Generation During the Transition

As long as a Distribution Company owns generation assets, the sale of power produced by those assets continues to be regulated by the Department; specifically, all power it provides to its customers (including its own power) is sold at the spot price as Basic Service. No such price constraint is imposed on power sold outside its territory.

14. Separation of the Generation Function

By December of the year 2000, electric companies divest their competitive generation functions from monopoly "wires" functions. Once each electric company has divested its non-T&D assets, and has divested its retail function (as described in section 10 above), no restriction will remain on sales by the new owners of those competitive services to customers in the remaining Distribution Company's territory.

15. Energy Efficiency/Renewable Energy Technologies

Throughout the transition process, Distribution Companies maintain current levels of cost-effective demand-side management ("DSM") and renewable energy programs not otherwise provided by retail suppliers. Distribution Companies respond to incentive regulation to encourage distributed generation where cost-effective as an alternative to distribution system upgrades. DSM and renewable energy programs of Distribution Companies are reviewed periodically by the Department to ensure cost-effectiveness.

C. Participants In A Restructured Electric Industry

A restructured electric industry will be populated by a variety of participants. These participants will be differentiated by whether they operate at the wholesale or retail level and by whether they are regulated or unregulated entities. The table below identifies some, though not all, of the likely participants and categorizes them by their distinguishing features.

A description of the role each of these participants is likely to play in a restructured industry can be found in **Appendix A.**

PARTICIPANTS in a RESTRUCTURED ELECTRIC INDUSTRY

	REGULATED	COMPETITIVE
WHOLESALE	Independent System Operator Power Exchange	Generators Marketers Brokers Spot and Futures Markets
RETAIL	Distribution Companies	Retailers Load Aggregators Energy Service Companies

III. CONSISTENCY OF PLAN WITH THE DEPARTMENT'S AUGUST ORDER

A. Principles For A Restructured Electric Industry

1. *Provide the broadest possible customer choice.*²

The broadest choice requires a synergistic market structure based on the availability to customers of both contract and spot market options, which customers and their suppliers may combine as they wish. These options are discussed in turn below.

a. Role of Bilateral Contracts in Customer Choice

This **Power Choice** plan creates a new right for retail customers to choose their power supply provider and negotiate a bilateral agreement with that provider for delivery of power. This right does not exist today. **Power Choice** secures this right for all retail customers and creates structures that will protect and facilitate the exercise of this right.

Bilateral contracts enable customers to make their best deals for generation supply with whomever in the competitive market is most effective at meeting their needs. Allowing generators to contract directly with customers, marketers, or retailers creates competition on both sides of the transaction. Generators compete among themselves to supply this demand. This gives customers and their representatives a full range of choice among generators. Generators may charge any price the market will bear and may choose to compete not only by price but by contract duration, payment terms, type of generation and type of electric service. Thus, bilateral contracts will provide a wide range of choices to meet various customer needs.

In addition, bilateral contracts enable customers to have broad choice among the types of suppliers. Some customers may be large enough to deal directly with a generator or be able to purchase power through a Marketer, Broker or Energy Service Company. Smaller customers will have choices among retailers, load aggregators and

² The Department's August Order set forth seven principles for a restructured electric industry of which this is the first. The discussion that follows analyzes the **Power Choice** plan for consistency with each of the seven principles. Transition principles are presented in the same fashion beginning in Section III.B.

Energy Service Companies who can aggregate their needs and obtain price advantages from volume, timing, duration and other characteristics of customer needs. Competition among all these various service providers is enabled by the customers' ability to execute bilateral contracts.

Generators will enter into bilateral contracts with customers and other participants. This enables generators to become retailers or to affiliate with retailers or marketers. This provides additional opportunities for new firms to enter the generation market which will keep it competitive.

At the wholesale level, bilateral contracts are facilitated in the Plan by the protocols of the ISO which will be responsible for scheduling and providing transmission service for bilateral contracts, as described further in section III.A.3. below.

b. Role of Spot Market in Customer Choice

Power Choice envisions the establishment of a New England Power Exchange³ in which energy may be bought and sold, which will enhance competition and provide the basis of Basic Service (see Section II.A.4). The Power Exchange will provide a mechanism through which power supply and demand-related products not met through bilateral contracts can be sold and purchased. The Power Exchange will conduct an hourly energy auction in which any supplier may offer to sell a specified amount of energy with specified start-up times and other operating conditions as required. The Power Exchange will rank these offers in order of price (modified by any operating constraints), and compare these supply offers to anticipated load in every hour. This will determine the hourly clearing price -- to be paid to all suppliers and by all buyers -- and a projected order schedule to be submitted to suppliers and the ISO.

Market participants will have access to clear and transparent price information. The Power Exchange will meet this need by enabling customers to compare offers to the price of electricity on the Power Exchange.

While spot markets are likely to develop without the explicit establishment of the Power Exchange, it is important to have the services that will be provided by the Power Exchange available as soon as generation pricing is deregulated. If no Power Exchange or other spot market provider were in place immediately, the lack of

³ See Section II.B.4.

information would inhibit purchasers from making informed decisions. Without this mechanism, the restructured system will heavily favor very large entities.

The existence of a Power Exchange should make it possible for more entities to participate and more products to be offered in the energy market. For instance, some generators might choose to provide baseload power to customers on the basis of bilateral contracts, while the customers could meet any additional power needs (e.g., for peaking) through purchases on the spot market. The Power Exchange will also accept comparable "demand-side" bids from customers who are willing to have their load interrupted at specified times and prices.

Participation in the Power Exchange should be entirely voluntary, except where it is determined that participation may be necessary to preclude the use of market power. Some entities will choose providers of spot market services outside the Power Exchange, and some will choose to buy and sell primarily through the mechanism of bilateral contracts.

The Power Exchange, together with other spot and futures market services expected to be available in the region, will constitute a robust market for short-term power with transparent prices, and this market will lead to the lowest system prices. In such an active market, spot prices at the Power Exchange and from other spot suppliers will not diverge significantly. In this regional spot market, generation at higher than the market price will not sell; purchasers will always receive (or be able to find) the market-clearing price.

The lack of an effective spot market at the outset would be a market barrier allowing sellers to discriminate and charge higher prices to some purchasers. The spot market and bilateral contracts will each check pressures in the other toward price increases and, together, provide a competitive range of generation options for customers. Without a Power Exchange, there would be a potential for very large volume sellers to dominate the market and raise the market-clearing price particularly in the early years of the transition process.

Since New England power plants have been centrally dispatched for almost thirty years, the New England electricity industry is more familiar with the equivalent of a central energy market than the industry in other regional control areas. Few utilities have generation portfolios that are perfectly suited to meet their load at all times. Generation costs have been reduced by a sharing of resources through centralized dispatch. The creation of a Power Exchange frees each load-serving entity from the need to individually optimize its own power supply through trades. Many smaller utilities are not equipped to perform the latter function, and contracting for

such services might create significant transaction costs. With a regional Power Exchange, for instance, municipal utilities would have the opportunity to bid some or all of their generation and purchase some or all of their needs from the Power Exchange. The Power Exchange should thus contribute to holding down prices for smaller buyers.

c. Packaged Services

Competition will result in a wide variety of packaged electricity services for generation supply. For example, energy service companies specializing in providing services related to energy utilization and management have historically included financing and sharing of energy savings as part of their service. In the future, the competitive market will determine how these services will be structured. Energy Service Companies may contract directly with consumers or through retailers, marketers, brokers or load aggregators, and their offerings are likely to include a broad range of energy related services including risk management for both price and supply fluctuations.

The existence of different types of suppliers and different types of products (bundled generation versus spot generation, long-term versus spot, etc.) will provide additional choices to consumers and advance a truly competitive marketplace. Competitors may attempt to provide service that is more economic or more secure or has less price volatility than the spot market through the provision of bilateral contracts or a service that is a combination of bilateral and spot purchases. These services will succeed if they meet the needs of purchasers.

d. Load Aggregation

Customers will be free to form buyers' cooperatives or associations to act on their behalf or to contract with load aggregators, municipal or private, to obtain their electricity services. Load Aggregators will be municipal or private entities that organize customers in order to obtain more favorable contracts from retailers or marketers; they will be agents who specialize in bringing buyers together. They will not take title to the electricity but instead provide the service of arranging purchases for multiple customers. They may also arrange for additional services and negotiate contract terms with retailers and Energy Service Companies for their clients.

Legislation has been introduced in the Massachusetts General Court that would permit cities and towns, without municipal light departments, to become Municipal Retail Load Aggregators. As proposed, Municipal Retail Load Aggregators would be able to provide the load aggregation services for inhabitants of a municipality but would not restrict the right of individual customers to contract directly for generation services.

2. *Provide all customers with an opportunity to share in the benefits of increased competition.*

Power Choice provides all customers the opportunity to share in the benefits of increased competition in at least three significant ways: 1) immediate retail competition for all; 2) basic service available for all; and 3) pilots for all classes.

Power Choice is designed to achieve a full and fair retail competition for all customers, not just particular customer groups based on size, load characteristics or existing metering. With the proposed market structure, full and fair competition means that all customer classes can have their choice of supplier simultaneously. This competition among retailers will provide the benefits of wholesale competition to all classes and sizes of customers. **Power Choice** also provides for the use of hourly load curves to represent usage patterns of customers without hourly meters. This provides all customers with the means to participate in generation services which require hourly pricing, such as the spot market. Furthermore, the Plan provides for municipal retail and other load aggregators to group customers of all sizes in interested municipalities and other interested customers, respectively, for purposes of obtaining the benefits of purchasing in bulk.

Secondly, **Power Choice's** Basic Service, described in connection with Universal Service below, is also designed for all classes of customers. Basic Service will permit the benefits of competition in generation to be available to all customers who do not desire to select a competitive retailer or Load Aggregator and to any customer who cannot for any reason at any time obtain competitive service for generation supply. Basic Service accesses the spot market for power. All customers served under Basic Service will automatically obtain the benefits of the spot market.

Thirdly, **Power Choice's** proposed pilot programs are designed to provide an equal percentage of each customer class with experience with retail choice during the transition. Specifically, 10 percent of the sales, or customers, whichever is greater, of each customer class will be included in pilots.

3. *Ensure full and fair competition in generation markets.*

a. Open Access to Generation Suppliers

In order to have fair and open competition among producers, transmission of power must be accessible to all generators on the same terms. **Power Choice** anticipates the establishment of an Independent System Operator (ISO) that will provide assurance to all generators that they have full and equal access to the transmission system. Customers may select any generator without increasing their cost of transmission (unless due to locational factors specified in the ISO Transmission Tariffs) or decreasing reliability of delivery.

The ISO must be fully independent of owners of generation to ensure that system operations do not advantage some generators or interfere with customer access. While NEPOOL currently functions as a system operator, NEPOOL is owned and managed by utility owners of generation. The separation of transmission control from generation owners will ensure that they cannot influence operation of the transmission system to their advantage or to the disadvantage of generators who do not own transmission.

b. Reliability

Reliable service is critical to successful restructuring. **Power Choice** preserves the reliability of the current system, while providing a structure in which competition is fully compatible with reliability.

The Independent System Operator will be charged with maintaining reliability of the electric power transmission system. The nature of electricity is such that both demand and supply vary from even near-term projections and plans. Yet variance between the quantity demanded and the quantity supplied could jeopardize reliability of the entire system. For instance, if the quantity supplied in the next 15 minutes were inadequate to meet load, it would cause voltage and then frequency to drop, which would then cause generating units to trip automatically throughout the system. The ISO will avoid such situations by bringing up additional generation as soon as needed, or will minimize them by isolating the failure to one geographic area. Reliability is enhanced when a single entity has the ability to adjust flows on the transmission network.

Reliability has its cost, but essentially an externality -- that is, reliability provided by one participant benefits all participants. An individual generator, attempting to provide reserves, would have higher prices than a generator without

reserves, and would be at a short-term disadvantage. If the only incentive to maintain operating reserves and appropriate levels of reliability were to be the reactions of customers when their power supply is interrupted, their decisions would not likely be sufficient to maintain the reliability of the entire system.

The existence of an ISO also makes a given level of reliability less expensive than it would be for a multitude of uncoordinated participants. The ISO facilitates the sharing of reserves, so that fewer reserves provide the same level of reliability.

To ensure reliability, the ISO will manage deliveries over the transmission system. The New England electric system entails a large number of generators producing power for a large number of users -- power which is delivered over transmission assets owned by a number of companies. In order to deliver power reliably, transmission must be scheduled so that generation decisions do not create congestion or overload of the transmission system. Although a system operator would have value in most areas, it is crucial in New England because of the large number of generators and transmission owners whose operations must be synchronized and integrated. The ISO will, therefore, develop protocols to resolve transmission constraints, as NEPOOL does currently.

Reliability also requires that the ISO have some degree of control over a limited amount of generation. There will remain a need to redispatch some generation on a real-time basis. For instance, load decreases may require that some generation be backed down. Or, a failure of a major transmission line might render the transmission system incapable of delivering all of the scheduled power to a particular location. Similar situations arise with regard to increasing generation. The ISO will therefore have the authority to exercise this kind of control over all units as needed to assure the safety and reliability of the grid, and may enter into contracts for specific capacity rights on which it can call for reliability purposes.

The ISO may also act to maintain reliability by buying from the Power Exchange when needed. This will depend upon how much generation is committed on a bilateral basis and how much is being sold on the Power Exchange. In order to make such decisions efficiently, the ISO will need information about relative prices. It will not require prices for particular generators from the Power Exchange, but could instead be guided by a ranking provided by the Power Exchange based on confidential price bids.

c. Vertical Market Power

Under this plan, transmission will be completely under the control of the ISO and not under the control of generation owners. Otherwise, generators with access to transmission information or control of operating rules could gain advantages over other market participants. For instance, transmission or generation failure would mean the clearing price would increase. Advance knowledge of these occurrences would enable the generation owners with this information to increase their bid prices. Creating full independence for the system operator will avoid any such exercise of vertical market power, while ensuring reliability of transmission and comparability of access to all users. One effective way to accomplish these ends will be for the ISO to acquire leases on all existing transmission capacity from current owners.

Recently NEPOOL proposed a series of reforms known as "NEPOOL Plus".⁴ The changes that are contemplated in NEPOOL Plus would not create a truly independent system operator. As long as a system operator remains owned and governed by owners of generation, neither customers nor generators can be assured that it will provide fair and equal access to all competitors. Furthermore, NEPOOL Plus does not appear to result in a fully market-oriented system. For example, the continuation of own-load dispatch would make it difficult for a load aggregator to be supplied from the spot market or for a generator to sell into a spot market. Also, although NEPOOL is designating additional generation "products", it does not appear that the increase in utility capacity responsibilities would increase system flexibility or assist in customer choice. In addition, it does not appear that NEPOOL Plus would create the ability for participants to acquire operating reserves from the pool, which appears to disadvantage smaller players and does not allow the market to play a role in selecting cost-effective reserves.

The changes promised under NEPOOL Plus begin the process of reforming NEPOOL into a more independent operator, and would create some incentives for more competitive behavior among generators. However further changes will be necessary to develop a genuine spot market system that encourages full development of competition and retail access. DOER supports the recent resolution of the New England Conference of Public Utility Commissioners that requests the NEPOOL Executive Committee to propose a complete reorganization to FERC by July 1, 1996.⁵

⁴ NEPOOL Plus, Summary Vision for a Restructured NEPOOL. January 5, 1996. NEPOOL Executive Committee.

⁵ Resolution of NECPUC. January 11, 1996.

d. Uniform Tariff

To insure that transmission rates are fair and transparent to all users, the ISO (subject to FERC approval) must be responsible for setting transmission rates that will be applicable to all system users. When the ISO sets transmission rates, participants will have assurance of equal treatment. Should a Regional Transmission Group (RTG) be formed, we would anticipate it would work closely with the ISO to establish these rates.

Equal treatment cannot be assured by transmission owners who charge "comparable" tariffs, even with regulatory oversight. For example, if the most likely sites for new generation are at greater distances from demand than existing generation, transmission rates that are distance sensitive will disadvantage such new generation. It will be very difficult to distinguish whether increased prices reflect cost differences due to distance or reflect merely arbitrary premiums intended to disadvantage new competitors. The ISO will eliminate or mitigate any such interference with the competitive market.

4. *Functionally separate generation, transmission, and distribution services.*

While rejecting mandatory divestiture as a remedy at the time of the August Order, the Department has declared that "[v]ertical integration and horizontal market power, with their potential for anticompetitive behavior and consequent reduction in benefits to customers, must not obstruct the development of a generation market that includes a wide variety of viable competitors." Order at 23. Shaping a truly competitive market from a patchwork of regulated, fully integrated monopolies and other suppliers will be a daunting task. Creation of a truly competitive generation market will require utilities to voluntarily divest those assets which are not needed to supply Transmission and Distribution Services ("non-T&D assets"). DOER views voluntary divestiture not as end but as a means to ensure a full and fair competitive market, in order for customers to achieve the resulting price benefits.

a. Vertical Market Power

(1) Separate Generation from Distribution and Transmission

Power Choice provides that by December of the year 2000, electric companies divest their competitive generation functions from their monopoly "wires" functions. Divestiture would be accomplished via an auction or spin-off of such assets to a new company with separate stock and no directors in common with the directors of the Distribution Company.

(2) Separate the Remaining Retail Functions from Distribution

The Department recognized that distribution will remain a monopoly service (Order at 28) and that "[s]tate regulation should ensure that owners of distribution facilities do not use such ownership to hinder the competitive generation market or to prevent effective choice of supplier by customers." Order at 29. To achieve this important Department objective, Distribution Companies must be legally separate from both generators and retailers. Distribution Companies must not have both monopoly power and competitive objectives.

The monopoly Distribution Company uniquely controls access to customers by virtue of its exclusive connection with the customer. It also enjoys a long history of being the exclusive electric service provider to the customer. If Distribution Companies or affiliates were to sell competitive services to retail customers, their

involvement in the market would present formidable barriers to new entrants, and create potential for abuse of market power to limit future competition. For example, the Distribution Company could use its knowledge and relationships with customers to lock in the most profitable customers for its own competitive services.

Power Choice, therefore, provides that each electric company create a new, separately owned, unregulated retail company. Specifically, the utility would shift at least the following resources to the new "retailer:"

- the entire field sales force for business customers;
- field offices used for sales and promotional activity;⁶
- all retail service packages, "branded" or otherwise;
- some components of current DSM programs;⁷
- the generation planning staff and infrastructure, and
- all headquarters or overhead operations not demonstrated to be needed to administer the remaining wires and related monopoly functions.

The separation of the Distribution Company from the retail functions will be accomplished by an auction or spin-off of the retail business. In either case, the separation will be conducted in cooperation with an accounting firm selected by and reporting to the Department. The proceeds from the auction or the market value derived from the spin-off would be netted against any claimed stranded costs as a mitigation measure.

Limiting Distribution Companies to "wires-only" activities furthers the Department's objective to promote the broadest customer choice. If the ownership of Distribution Companies were not to limit their economic interests to the regulated

⁶ The Distribution Company could retain field offices to serve the needs of customers regarding bill payment problems and the like pertaining to Distribution Service.

⁷ All "lost-opportunity" or "time-dependent" DSM services would initially remain with the Distribution Company as regulated monopoly services.

distribution business then there would remain opportunities to cross-subsidize prices, create unequal barriers to sell to customers, and self deal.

The corporate name of the new retailer will need to be sufficiently distinct from the name associated with the former electric company and the new Distribution Company to avoid creating customer confusion, and to assure that the new retailer would not be in a position to use that name to exercise undue market power or create barriers to entry of new competitive retailers.

(3) Lease Transmission Assets to the ISO

Power Choice includes the creation of an ISO not later than January of 1997. As discussed in detail in Section III.A.3.d, the leasing of transmission assets to the ISO for its management is necessary to limit vertical market power and ensure full and fair competition.

b. Horizontal Market Power

In the current electricity market, there is a high concentration of generation assets in the hands of a small number of electric companies. The persistence of the horizontal integration that exists in New England today, or an increase due to mergers or acquisitions, are potentially a threat to a full and fair competition. For example, bilateral contracts or spot market prices could be manipulated by large generating companies to produce oligopoly pricing behavior (e.g., collusion, price floors, etc).⁸ Any practice or market complication which reduces consumers' information or interest in prices prevents the price mechanism, which is central to a competitive market, from influencing patterns and trends in demand. Companies with large market share may develop strategies to withhold production to maintain prices, either separately or in collusion with others. Even the spot market could be manipulated, possibly without any explicit price fixing agreements among generators. Influencing markets via methods other than price competition (e.g. marketing, advertising, product differentiation, etc.), threatens the long run success of restructuring.

⁸ Oligopolistic price leadership comes in three varieties: "dominant firm", where one firm is so large that its activities dominate price determination and are obvious enough for other firms to follow, "barometric" where all the large firms understand the process and watch the same signals for opportunities to raise prices, and "collusive" where companies make explicit and illicit price deals.

The more inelastic the demand of consumers, the less market power is needed to exploit consumers by withholding production and raising prices. Excess capacity in an industry coupled with lower capacity utilization, provides greater incentive to use market power to raise prices and to exclude new entrants.

Assuming voluntary divestiture, generation assets will be transferred from existing utilities to generating companies. During the course of those transfers, the Massachusetts Attorney General, FERC, the SEC and the U.S. Justice Department will have an opportunity to review the degree of concentration of those assets.

c. Incentive Regulation and Threat of Antitrust Litigation
Not Sufficient

Functional unbundling without divestiture is an invitation to endless disputes and an anemic market. Moreover, it would require more bureaucracy, not less. Enforcement of functional unbundling would require constant policing, a complaint resolution process and greater oversight of both monopoly and competitive functions. At the same time, retailers without a Distribution Company affiliation may suspect anticompetitive motivation for every conflict with a Distribution Company. Every time a retailer believes it was unfairly treated in a transaction with the Distribution Company it will be likely to pursue administrative remedies at the Department. Every time a retailer believes itself unfairly beaten in the competitive marketplace by the Distribution Company affiliate it will consider seeking Department review. A new bureaucracy may be needed to handle the volume of complaints of anticompetitive behavior and practices. Additional regulation will cost all parties, and ultimately consumers, more.

Even with adequate staffing and volumes of new rules and procedures, the perception may persist that the market is biased. This will diminish the enthusiasm to enter the market. Even if regulation could minimize abuses of functionally separate regulated and unregulated activities, this structure creates the incentive for gaming and testing the regulatory boundary for the pursuit of profits for shareholders. Not fully separating the economic interests of these functions will substantially increase the need for regulatory oversight.

Moreover, hundreds of utilities across the nation will be undergoing some form of restructuring before the end of the decade. It is unrealistic to rely on the U.S. Justice Department or FERC to adequately police anticompetitive practices of all vertically integrated utilities. It is far preferable to restructure today's electric companies at the outset in a manner which is inherently less likely to provide opportunities for anticompetitive practices.

5. *Provide universal service.*

a. Universal Service/Consumer Protection

Under the current regulatory structure, electric utilities have what is referred to as "an obligation to serve." That obligation is, in fact, a bundle of obligations including the following:

- an obligation to serve any customer within the company's franchise area who requests service;
- an obligation to provide safe and reliable service;
- an obligation to serve all customers on a non-discriminatory basis; and
- an obligation to charge "just and reasonable" rates as determined by the Department or FERC.

Under **Power Choice**, the Distribution Company would have an obligation to provide connection and Distribution Service to any customer in its geographic region. The Distribution Company would also have an obligation to make available power from the spot market at the spot market price on a non-discriminatory basis to any customer. These distribution-related obligations of the Distribution Company would, of course, be subject to all current consumer protections and obligations regarding bill payments and shut-offs. Bad debt incurred by the Distribution Company as a result of customers' failure to pay would be recoverable under the incentive-based rates approved by the Department.

(1) Guaranteed Access to Electricity

With **Power Choice**, all customers will be guaranteed access to electricity. Universal electric service will be replaced with a combination of the obligation to connect and the obligation to provide Basic Service. These obligations will be placed on the regulated Distribution Company. In addition, the role of load aggregators will be encouraged.

(2) Consumers' Rights

Power Choice would continue current Department policies regarding shut-off protections. **Power Choice** also endorses expansion of the Department's authority to prohibit redlining. In other industries where some aspects are competitive and others

remain regulated, such as banking and insurance, discrimination has taken the form of restricting service from specific geographic areas. The obligation to connect of Distribution Companies will insure connection of all consumers. Basic Service will insure that no one goes without service. The certification of retailers should include a prohibition against discrimination on a geographic basis, as well as a means for specifying the terms and conditions under which retailers can terminate service.

b. Affordability for Low Income Consumers

Power Choice is designed to meet the diverse needs of all of the Commonwealth's ratepayers. Distribution Rates should provide revenues sufficient to maintain current low income programs, and Distribution Companies should be required to continue those programs.

c. Basic Service for Non-Contract Customers

Electricity service must continue to be provided to all consumers. Therefore, Distribution Companies will be required to provide a Basic Service. This service will be available to all customers who do not choose to contract directly for electricity and to any customer who, for any reason, is not offered or cannot obtain a direct contract. Distribution Companies will be required to use the spot market to obtain the electricity for this service.

(1) Maintaining Universal Electric Service in a
Competitive Market

There is a legitimate concern, based on the experience with long distance telephone deregulation, that as we transition from regulated electric service with its obligation to serve, to a competitive market based on customer choice, it may take some time for all customers to be comfortable choosing among suppliers. Customers who simply do not choose or, still others who for whatever reason may not be offered or be able to obtain service, must still receive it. Because electricity is a necessity, there should be provision for a Basic Service for these non-contracted customers. In this way, universal electric service, subject to the same bill payment enforcement and consumer protection provisions, will be maintained in a competitive market. Basic Service avoids the confusion and interference that would result from random or forced assignment of these consumers to unfamiliar suppliers, avoids forcing consumers to choose suppliers until they are prepared to choose, and protects consumers aware of Basic Service from overzealous marketers.

(2) Benefits of Competition Obtained by All Customers

Basic Service can also provide some of the benefits of competition in power supply to even these customers who might not otherwise benefit from retail competition. Under **Power Choice**, the generation supply for this Basic Service will be obtained in the competitive spot market and the benefits of this marketplace passed through to these non-contracted customers. Thus, the design of Basic Service will help achieve the objective of everyone obtaining the benefits of restructuring.

(3) Supports a Competitive Spot Market

By serving the Basic Service load through the spot market, there will be a larger load serviced by market electricity. The greater the competition, the more likely that the spot market price will represent the true competitive cost of electricity and result in lower costs overall to consumers. The larger this load and the greater the number of suppliers, the less risk that dominant generators could manipulate the market for their benefit by withholding supply or coordinating their bids.

(4) Encourages Distribution Companies to Divest Generation

If the Basic Service load is supplied through the spot market, Distribution Companies will not have incentives to hold onto generation to serve the Distribution Companies' customers.

(5) Minimizes Risk of Anticompetitive Effects

Basic Service is effectively a retail electric service which represents an alternative to those services to be offered by competitive retailers. And while Basic Service should not inhibit the development of competitive retail services, it is likely that many consumers will utilize Basic Service. Compared to the alternatives, using spot market prices for Basic Service is the least distorting of the market while most protective of consumers. Alternatives, such as assigning all customers randomly among qualifying retailers would be confusing and disruptive to customers. Permitting the Distribution Company to also be a competitive retailer would raise a host of self-dealing and regulatory burdens. (See Section III.A.4.c.) Further, limiting Basic Service to the provision of generation priced at the spot market means that retailers who can offer additional services with generation will be able to easily differentiate their services from Basic Service. This will minimize anticompetitive effects of Basic Service.

(6) Promotes Competitive Services

A related benefit of Basic Service is that it will serve as the benchmark for competitive services. Basic Service will set a standard that will be universally available to any customer against which to compare competitive offers. Customers who do not initially choose a competitive service offered by a retailer, will nevertheless obtain their electricity from the competitive market. Their experience with this alternative to cost-of-service pricing should assist their transition to more active participation in the competitive market. Thus, the Basic Service strikes an appropriate balance between a non-competitive safety net for transition to a competitive retail market and a minimum standard against which some of the competitive benefits of competition can be measured.

(7) Spot Market Electricity Will Not Result in Volatile Basic Service Prices

The Basic Service generation component (i.e., the spot price) will be only about a third of most customers' electric bills. Thus, up to two-thirds of electric bills of all customers will consist of regulated rates for distribution and transition charges and will neither fluctuate widely nor increase unexpectedly. Basic Service customers will not face hourly prices. Most Basic Service customers, without hourly metering, will be billed using average load curves which will average spot market prices over all their hours of use. Combining hourly spot market prices over a month will significantly dampen the normal hourly variation. Additional analyses have shown that the month-to-month variation in average variable operating costs (the closest proxy today for a spot market) are minimal. Moreover, long term contract prices of commodities tend to follow the price in the spot market, on average. Consequently, there should be no great variation between these prices and the Basic Service generation costs. Some variation in price is to be expected, just as customers are currently exposed to seasonal variation and fuel price variation in cost-of-service rates.

(8) Contingency

During the initial months after price deregulation, the spot market to which Massachusetts electric companies have access may be limited in scope or pricing arrangements. In this event, the Distribution Company would procure electricity for its Basic Service customers through competitive bidding for short-term wholesale contracts (i.e., less than 6 months in duration for any individual contract), and would then pass through this market pricing to the customers.

(9) Terms of Service

In general, Basic Service would automatically be provided to any customer 1) who has not notified the Distribution Company and had the retailer verify his or her selection, 2) whose retailer fails to meet its contract obligations for electricity supply to the customer, or 3) who is dropped by the retailer for any reason, including for non-payment. This provides a safety net for electricity, an essential service.

Customers may request Basic Service at any time and without restriction on the number of times they may exit and return. Voluntary requests are subject to standard verification by retailers to the Distribution Company and time required to process the change in retailer. Two weeks should be sufficient.

Customers may switch from Basic Service at the end of a month subject to the standard notification of retailers and time required to process the change.

6. *Support and further the goals of environmental regulation.*

Power Choice provides several mechanisms for compliance with the Department's principle to "support and further the goals of environmental regulation": reduced air emissions from existing units, competitive DSM investments, and the commercialization of renewable and low-emission technologies⁹. The specifics of each mechanism follow:

a. **Air Emission Reductions and Other Environmental Improvements**

The Department observed in its August Order that "[i]f different environmental requirements are imposed on similar generators or groups of generators, ...competition may be distorted." Order at 27. Older fossil units, especially those built before the 1990 Clean Air Amendments, are subject to less stringent emissions control requirements than units of like fuel built today. As a consequence, the marginal costs of these units are typically lower than they would be if they had to meet new unit emissions standards. In a competitive retail market, the lower marginal costs of these units could allow their owners to run them more often and for longer than the units' previously-expected lifetimes. Newer, cleaner units that are still bearing initial capital costs will be at a competitive disadvantage. The result, absent investments to bring older plants up to the same emissions standards as newer plants, would be dirtier air in Massachusetts and in downwind states, and a distinct market disadvantage to new, cleaner market entrants. Consequently, **Power Choice** envisions agreements between utilities, the Department of Environmental Protection (DEP), and other parties to achieve a more level playing field.

Each agreement would include enforceable commitments for the electric company or any entity that takes title to its generating unit(s) to do the following:

⁹Low-emission technologies refer to fuel cells. For ease of exposition, the term "renewables" includes low-emission technologies.

- reduce the average nitrogen oxide emissions of its oil/coal portfolio¹⁰ to 0.15 lb/mmBtu by December, 1999;
- reduce the sulfur dioxide emissions of its oil/coal portfolio of oil and coal plants to 0.2 lb/mmBtu also by December, 1999.
- reduce the net CO2 emissions of its oil/coal portfolio by 20 percent from its 1990 emission levels;
- conforms its portfolio emissions to comply with all future air toxics standards and deadlines promulgated for new power plants by state and federal environmental agencies, regardless of any federal "grandfather" exemptions.

Companies can accomplish these air emission reductions, via any combination of control technologies, fuel switching, repowering, plant retirements, replacement of existing portfolio plants with cleaner sources or power purchases from cleaner resources (including renewables and low emission sources and energy efficiency resources). In addition, the use of certified emission reduction credits and allowances is strongly encouraged.

Power Choice also endorses the use of all reasonable means to apply these same standards to competing sellers of power to retail Massachusetts customers whose portfolio of generation sources include plants outside Massachusetts. DOER will work with DEP, utilities and other parties to develop specific steps, including working with government agencies, federal and state legislators, other utilities, and other parties, to obtain the same environmental commitments from all retail suppliers.

b. Competitive Demand-Side Management

Demand-side management (DSM) services produce significant environmental benefits by reducing system-wide emissions through reduced peak and increased average load factors. Restructuring will increase demand for DSM services which are market-ready. Time-of-use pricing, new technologies to manage energy use, and

¹⁰"Portfolio" is defined as those generating units fired in whole or in part by oil or coal, whether located in Massachusetts or elsewhere, that are owned, operated, or selling power under contract to Massachusetts utilities. If title to a plant is transferred after agreement is reached, the transfer must be made subject to the new owner implementing equivalent reductions.

bundling of conservation with electricity by suppliers are just a few examples of the innovations that will help expand DSM's impact on the electricity marketplace. Central to the success of DSM is the degree to which the market for generation is fully and fairly deregulated and the degree to which power suppliers are prevented from the exercise of market power. (DSM programs sponsored by the Distribution Company through the transition are discussed in Section III.B.4 below.)

c. Renewables Technologies

Renewables and other low-emission technologies also produce significant environmental benefits. Technologies such as hydro, wind, biomass and photovoltaics face uncertain prospects in a more competitive generation market. Under current industry regulation, utilities are encouraged to develop these resources for their long term social benefits.¹¹ Under the market structure proposed in **Power Choice**, market mechanisms are proposed to accomplish this same goal. There should be commitments to support research on and commercial development of renewable and low-emission technologies through the transition process.

Customer choice in the retail market for electricity will provide direct, non-discriminatory retail access to all customers for renewable generators and marketers. This will help create a demand for generation from these resources and overcome an existing barrier in the market. These generators will no longer need to take responsibility for all customer requirements nor be penalized for the intermittent nature of some of their generation. Customers requiring back-up service will be able to obtain it through Basic Service from the spot market. In **Power Choice** this is accomplished quickly and simultaneously for all consumers. The Power Exchange will also provide an opportunity for renewable and small generators to sell part or all of their power without the hurdle of first signing power sales contracts.

Power Choice's incentive regulation for Distribution Companies creates a market mechanism that will recognize and reward least-cost distributed generation (i.e., strategically placed, smaller generation facilities that reduce the need for new

¹¹ This policy will continue under **Power Choice** for as long as Distribution Companies or their affiliates own generation. This would be accomplished by using the formula to set rates for Distribution Service to provide an incentive to include an appropriate level of investment in renewable resource development.

transmission and distribution facilities). Distributed generation using renewables can potentially displace more costly expansions to both the transmission and distribution system.

Power Choice anticipates that both new and existing generation resources will be subject to the same environmental requirements. In this context, the environmental benefits of renewables will be more accurately valued by the market than they are today. To capture additional environmental benefits, it may be necessary to enact legislation which sets appropriate levels for development of renewables. To facilitate policy-making, DOER will convene a working group to develop a commercialization plan for renewables.

7. *Rely on incentive regulation where a fully competitive market cannot exist, or does not yet exist.*

a. Distribution

Under **Power Choice**, the Distribution Company provides Distribution Service to all electric customers in its service territory, and Basic Service for customers who have not nominated an alternative supplier. Since the price of Basic Service -- the spot price -- will be passed through without a profit margin, it will not generally require incentive regulation, as discussed in section III.A.5.c. Any stranded costs associated with non-T&D assets will be collected in the transition charge, which will be set on an interim basis as part of each utility's rate case, and then finalized after the market valuation of those assets. Therefore, this section on incentive regulation does not address generation costs other than Basic Service and distributed generation.

Power Choice reflects the Department's finding that continued monopoly functions are better regulated by incentive ratemaking rather than the present, out-dated system of cost-of-service regulation. Some of the more obvious shortcomings of this methodology include the (1) "cost-plus" nature of pricing which limits and even undermines incentives for cost minimization, and (2) the incentive to expand utility ratebase investments, rather than purchasing potentially less expensive services. In addition, since the present pricing system is based on the embedded cost of service, regulators are virtually obligated to oversee utility management or to participate in the decisions that drive utility costs. Accordingly, extensive regulatory intervention in utility management decisions is required to ensure an acceptable level of utility costs.

Incentive regulation, in contrast to cost-of-service ratemaking, has the potential to give Distribution Companies better incentives to be economically efficient by allowing such Companies to retain more of the savings resulting from cost-effective decisions, and to bear a greater burden of costly decisions. Through the use of service quality adjustments and a rate-of-return bandwidth, which are described below, the incentive framework in **Power Choice** is designed to give a Distribution Company greater financial incentives to maintain service quality and still avoid confiscatory or exorbitant returns from the established class-specific revenue formulas.

The Distribution Service tariff should be:

- "broad-based", in that the revenue cap covers the full range of Distribution Company activities, giving the Company discretion to make appropriate tradeoffs among the range of business activities so as to minimize overall company costs;
- "class-specific", in that the revenue cap is determined on a customer-class basis in order to minimize the possibility of inappropriate cost-shifting among classes of customers;
- "service quality adjusted", in that the revenue cap is adjusted upward or downward depending on whether the Distribution Company's services, measured by objective indices, are improving or deteriorating, thereby discouraging companies from overly sacrificing the quality of their service for cost minimization;
- "revenue cap based", to encourage cost-effective distribution system load management, and to be consistent with the way Distribution Company costs are incurred; and
- "rate-of-return bandwidth based", to signal when the utility is earning exorbitant or confiscatory returns on net capital invested in monopoly distribution services.

The incentive formula should give Distribution Companies the incentive to cost-effectively reduce distribution system power losses by making such Companies bear the costs associated with such losses. Distribution power losses are a responsibility that can be placed on Distribution Companies through an incentive formula that reduces such losses. The incentive to compensate for such losses would level the playing field among competing investments such as power purchases, distribution capacity improvement or expansion, energy conservation and load management, and distributed generation resources. In addition, the provision of such an incentive could minimize administrative review of such investments. The incentive formula should give Distribution Companies sufficient revenues to pursue research, development and commercialization activities for promising technologies for distribution-level generation and efficiency.

Finally, certain costs incurred by Distribution Companies, particularly nuclear decommissioning and Low Income Protections, are recovered outside of the incentive formula, through a separate charge.

b. Transmission

Under **Power Choice** the regional ISO both leases transmission facilities and charges generators or purchasers for transmission and ancillary services. These transmission charges will be regulated by the FERC.

To the extent that any transmission service remains under the jurisdiction of the Department, the rates for such service will be incentive-based in a manner comparable to those described above for Distribution Services.

c. Generation

The Department indicated in its order that it "recognizes that full competition will only be achieved over time." While some features of a truly effective market will depend upon progress at the New England level, **Power Choice** will achieve a substantial degree of competition as soon as generation prices have been fully deregulated in mid-1997 and Distribution Service with direct access is initiated in January of 1998.

Since **Power Choice** primarily relies on the marketplace to provide generation incentives, it contains only two limited features of incentive regulation for the generation function:

Basic Service. To the extent that the price of Basic Service is a pass-through of only the spot market price, minimal oversight by the Department is required. However, if the Department finds in response to a complaint by a party that the spot market available to the Distribution Company is deficient in some way, the Department must provide some level of regulatory supervision of the Distribution Companies' power purchases on behalf of Basic Service customers. A form of incentive regulation might properly regulate generation prices during this interim period.¹²

Distributed Generation. The incentive regulation of distribution rates is designed to support and encourage Distribution Companies to identify distributed generation that is more cost-effective than "conventional"

¹² If the Department approves the use of transition contracts with affiliated or formerly affiliated generating units as part of the supply for Basic Service customers, the pricing of power under those contracts should be structured as a price cap to those customers as a group.

investments in distribution expansion. To be consistent with full separation of generation from distribution, however, the Distribution Company should not own such distributed generation (with possible exceptions where preferable from a technical point of view). Rather, it should make available to unregulated owners of distributed generation facilities the financial or rate credits that are based on a sharing of the net benefits to distribution ratepayers. These transactions would be subject to the incentive of the revenue cap on distribution and would be reviewed when that cap is reviewed.

B. Transition From A Regulated To A Competitive Industry Structure

1. *Honor existing commitments.*

a. Overview

The Department should provide each utility with a reasonable opportunity to recover those sunk costs that will become stranded as a result of retail competition. To qualify for recovery, such costs must be genuinely unavoidable and must be verified using a market-based standard. In addition, requests for recovery must demonstrate that the stranded costs are the result of a process which reduced them to the lowest possible level. Specifically, the stranded costs of the utility's non-T&D assets that are worth less than their book value must be offset by the surplus created when the market value of other assets exceeds their book value. To further minimize the level of stranded costs, independent generators and utilities should be given incentives to renegotiate existing power contracts having above-market prices. Other utility claims for stranded costs, for example those that may result due to liabilities already collected or employee benefit obligations could be resolved in adjudication at the Department.

Current utility law provides that a utility is entitled to a reasonable opportunity to recovery of and a return on its prudently-incurred investments. There is no guarantee of 100% recovery -- just a reasonable opportunity to recover. Current law also provides that, in circumstances where investments become technologically obsolete or uneconomic, the utility can expect, at best, recovery of no more than the actual cost of that investment, with no return on the unrecovered balance.

b. Asset Eligibility

In its August Order, the Department indicated that eligibility for stranded cost recovery would be restricted to those utility commitments which had been made as of the date of that Order. To the extent that obligations, or the book value of an asset as of that date have been subsequently reduced as a result of contract terminations or renegotiation, depreciation or some other means, those reductions should accrue to the benefit of ratepayers.¹³ To provide incentives to accomplish these reductions, there

¹³ For example, if a generating unit has been further depreciated during the period August 16, 1995 through the date its title is transferred as a result of an auction or spin-off, the amount of the proceeds derived from the sale or spin-off should be netted against the book value at the time of the transfer of title, not the book value as of August 16,

may be instances where it would be prudent for the Department to allow some portion of the amount that an obligation has been reduced to accrue to the benefit of shareholders, such as in the case of renegotiation of power contracts.

c. Mitigation of Stranded Costs by Market Valuation

The Department has mandated that stranded costs be mitigated "by all available and reasonable means" (Order at 37). It is essential to mitigate stranded costs associated with generation assets by applying a rigorous market test to determine if the assets which a utility claims will be stranded are indeed worth less than their book value, and are not eliminated altogether when netted with the utility's assets with a market value above book value.

To recover any stranded costs, utilities should obtain real market values for each of their assets not directly related to transmission and distribution (hereafter, "non-T&D assets") within a three year period from 1998 through 2000. This could be accomplished through sale by auction or by a stock valuation after a spin-off of those assets to a new, separately owned company created by the utility. As a last resort, an independent appraisal process, supervised by the Department, could be used for valuation, as long as separation of ownership is also achieved. Nuclear plants would be valued and/or sold without prior decommissioning liabilities, which would remain with the Distribution Company. In the event of an auction, a utility would have the option of matching the highest bid, and then spinning off to the assets to a separately owned entity. Market valuation of nuclear plants would take into account the fact that decommissioning liabilities incurred to the date of valuation would remain with the Distribution Company. (The mitigation of stranded costs related to Power Sales Agreements is discussed below in Section III.B.1.d.) By applying the revenues obtained from the auction to reduce stranded costs, customers' transition charges could be substantially lower and shorter in duration than would be the case if utilities did not voluntarily auction and divest themselves of those assets.¹⁴

Utilities would be provided with a reasonable opportunity to recover any unrecovered net book value of the stranded assets. They would also be allowed to recover an appropriate return on the outstanding balance. Since there is no significant

1995.

¹⁴ This stranded cost valuation approach is consistent with the approach recommended by the Senate's Post Audit and Oversight Committee in its recent report on restructuring.

risk to that recovery, that return should be limited to an overall rate equal to the embedded cost of debt associated with those assets.

While some assets will be uneconomic for the foreseeable future and will, therefore, produce less revenue in an auction than their net book value, other assets should command high prices. The assets most likely to produce substantial proceeds from an auction include certain generating facilities and associated land, undeveloped sites, and intellectual property. Site values include land, location, access to transmission lines, railroad lines, water, operating permits, legal rights, engineering and planning studies. High bids for many facilities can be expected because of the strategic importance of generating locations, and because of the motivation of both existing and new suppliers to maintain or expand initial capacity and market share in the new competitive environment. Non-nuclear generating assets (oil, gas and hydro, real estate, permits, etc.) are very likely to have great net value. Even nuclear plants, if divested of decommissioning liabilities, are likely to have significant market value in a competitive market.

Some have expressed concern that this approach will result in low prices for generation assets because of the large number of assets that would be offered for sale in a market that now has surplus capacity. These concerns can be addressed. First, utilities would be allowed up to three years to obtain a market value for each of these assets. This brings them and any other potential bidder considerably closer to the time (approximately five years from now) when supply forecasts show a dramatic decrease in the current power surplus. A realistic expectation of market behavior will also support higher price levels once full deregulation of generation prices has taken place.

Second, many of these assets have a remaining life well beyond the expected duration of the current surplus of generation capacity in New England. Any bidder estimating the true market value of any of these assets will closely estimate the future stream of net revenue that could be obtained from the asset over the course of its remaining useful life. Estimates of the future net revenue stream from any asset will be heavily influenced by bidder expectations of the future market price for generated power (or, in the case of land, its future development potential), future operating costs, and comparative advantages of alternative investment strategies. In short, bidders will look beyond the near-term surplus capacity to determine an asset's net present value over its remaining life. The great advantage of obtaining a market valuation of these assets is that it allows utilities, and indirectly ratepayers, to claim the benefit of these bids which are produced by the most optimistic estimate of the net present value of the asset, not just the estimate of the current owner.

This approach accurately measures stranded costs as well as mitigates them. While the value of certain categories of stranded costs, such as regulatory assets can be determined by a review of utility accounting data, the amount of stranded cost associated with generation investments and purchases is less straightforward. Reliance on market price projections for a one-time calculation of stranded costs puts ratepayers at tremendous risk for paying too much. Periodic true-ups are problematic as well, inviting gaming in the market and requiring vast regulatory resources for periodic true-up proceedings. In contrast, the price received at auction will be an accurate measure of market value of assets, and a reliable basis on which to determine any stranded costs associated with those assets.

d. Incentives to Renegotiate Above-market Power Sales Agreements

For some utilities, the above-market component of Power Sales Agreements (PSAs) with other utilities and Non-Utility Generators (NUGs) is likely to be a substantial portion of their total net verifiable stranded costs. In its August Order, the Department embraced the principle of honoring existing commitments including PSAs. At the same time, the Department adopted the position that utilities must use all reasonable means to mitigate otherwise stranded costs. Recognizing that PSAs should be honored and enforced by their terms, DOER understands that mitigation in this context may be difficult. However, to the extent that mitigation does not occur, the resulting transition charges may be high in cost and long in duration. If so, the onset of a truly competitive market will be postponed. That scenario is clearly not in the interest of customers, competitors, or the Massachusetts economy in general.

Therefore, during the transition, utilities, as buyers, should be encouraged to offer financial and other incentives to PSA holders that will foster mitigation of stranded costs. There are at least two specific means of mitigation which should be applied:

- First, those buyers and sellers who can agree on a contract termination amount and terms should each receive a bonus payment provided that the sum of the termination amount and the bonus payments is cost-effective for ratepayers.
- Second, the purchasing utility should auction its rights to the power available under each remaining PSA in its

portfolio. The proceeds derived from those sales should be netted against the remaining obligations under the PSAs to determine the amount of stranded cost eligible for recovery.

DOER recognizes that each PSA may contain specific terms and conditions limiting or influencing how mitigation measures may be applied. However, since PSAs can be amended by mutual consent with Department or FERC approval, any necessary amendments to facilitate these mitigation measures should be expedited.

e. Regulatory Assets

Recovery of stranded regulatory assets should require a clear showing that such assets are, in fact stranded, and that the company has a reasonable basis for expecting recovery.

f. Minimize Anticompetitive Effects of Collection

The Department Order cited the following two anticompetitive effects that should be avoided, among others:

A stranded cost charge ... could stifle competition by tying the provision of one service to another ... [or making] access to the competitive market artificially unattractive to customers of incumbent electric utilities. Order at 37.

Accordingly, **Power Choice** resolves the stranded cost problem in a manner that is competitively neutral. It does this by using a combination of three features:

- a true valuation by the marketplace of all assets associated with competitive functions (generation and retail sales),
- full separation of ownership of those competitive functions from the monopoly functions (T&D), and
- a Basic Service provided by the Distribution Company which minimizes reliance on any remaining utility-owned generation during the transition.

The result is that any stranded cost transition charges will not affect the competition between generators and other suppliers for the customer's business, and will not effect the customer's choice between one competitive supplier and another.

Therefore, the imposition of these charges will not delay "the development of a fully competitive market." (Order at 38). The benefits attributable to competition will begin to be achieved immediately, without waiting for a long transition, once generation pricing is deregulated and the Distribution Company has introduced spot-priced Basic Service and direct-access Distribution Service.

g. Timing of Recovery of Stranded Cost

Recovery of any stranded costs would be accomplished through a Distribution Company "competition transition charge" (transition charge) that all customers would be required to pay. The Department would allow interim recovery of estimated stranded costs during the period in which actual stranded costs would be determined. Transition charges would be capped by the Department for each company at different levels depending on their magnitude.

The Department expressed concern in its Order that "certain mechanisms for recovery of stranded costs may unduly delay significant reductions in electric rates...." and specified that "stranded costs should not be included in an access charge ... for a period greater than 10 years." Order at 38.

Power Choice makes it possible to meet this 10-year limit (with the exception of some nuclear charges) by calling for long-term power contracts to be sold into the market as explained in greater detail in section B.1.d. above. The result could be transactions in which utilities assign such contracts and/or the power under these contracts to third parties, and cash out early in the transition process or at least before the tenth year. If a utility's portfolio of long-term contracts has a market value which turns out to be negative, the net payment would be a disbursement from the utility, in which case it might be to the ratepayers' advantage to spread such payments over the full ten years.

As noted above, any stranded cost charges will be competitively neutral under this plan. There will be no need to accelerate the recovery of any transition charges to avoid anticompetitive effects. Indeed, it may be desirable to provide rate relief in the early years by deferring some stranded cost recovery until subsequent years.

h. Transfer Rights

The right to receive stranded cost payments should be transferable, with the characteristics of a financial security. Stranded cost recovery will be guaranteed by the regulatory process to be collected as a transition charge to all consumers based on volume of use. Since it will be an assured income stream, it will have value

comparable to a bond or other financial security, or guaranteed receivable. The Distribution Company should be able to sell this financial asset as it would any other financial asset. It would benefit from this sale to the extent it could put the proceeds to use in order to earn income or reduce expenses, thereby increasing net income above the income foregone from stranded cost recovery.

Given the continued regulation of the distribution function, ratepayers would benefit from this increase in net income. The Department Order mentions only the new generation owner as a possible buyer of this security, but making the security generally transferable would increase its liquidity and value in the marketplace.

Capitalizing stranded cost recovery in this way would be consistent with the other four issues enumerated by the Department. It would not mitigate stranded costs directly but would make it possible for distribution companies to offset transition costs by reducing distribution costs. It would further discourage anticompetitive practices associated with stranded costs because the Distribution Company would not be the recipient of stranded cost charges. This process could also speed the reduction of electric rates directly and develop the competitive market by increasing capital availability. It is completely consistent with non-discriminatory rate design and non-bypassability.

i. Impacts of Competition on Local Communities

Competition may alter the value of existing generation facilities. This may affect the property tax revenues that local communities receive from generation owners. If the units at a facility are devalued in a market environment, the amount of local taxes that the community receives could also decline; if the units are worth more than current assessments, or if the station attracts new investment from power developers seeking to build additional generating capacity, then the valuation -- and the local tax revenues -- could increase.

It is essential that the impact on a host community's property tax revenue be taken into consideration during the transition period. The net effect on local taxes will be difficult to assess prior to a true market evaluation of existing generating units and the facilities where they are located. The net impact will depend not only on the value of current installations, but also on a facility's potential for future generation. For example, repowering units at existing facilities would avoid the time and expense of siting and permitting a new location; existing facilities also have essential transmission infrastructure. The investment attracted to an existing site could off-set,

or exceed, any write-down of existing units. Nevertheless a major financial disruption to the local community could occur if tax revenues that the community had expected were reduced as a result of restructuring.

The market value of non-T&D utility assets will be measured in the asset valuation process. When the value of assets having potential significant community impacts is known, the net effect on local property taxes can be estimated. Utilities that receive stranded costs could be required to negotiate with affected communities to provide transitional assistance.

2. *Unbundle rates.*

In its August Order, the Department stated: "Rates for generation, transmission, distribution and ancillary services should be unbundled as soon as possible. This unbundling of rates is critical to provide both customers and competitors with the information they need to make decisions in a more competitive environment." Order at 30.

a. Avoid Cost Shifting

Accurate unbundling of rates is critical to the success of restructuring. **Power Choice** ensures the complete separation of competitive from monopoly functions, and therefore requires that unbundling also be done accurately. Such unbundling will avoid subsidization of competitive functions by regulated functions, which would create unfair competition and could scuttle the benefits of the marketplace for consumers. DOER's previously filed Proposed Draft Order, D.P.U. 95-30-A, recommended such unbundling with an Appendix identifying key functional and allocable cost categories.

b. Avoid Cross-Subsidies

Two critical cost categories are generation and retailing since these are becoming fully competitive. With respect to generation, it is critical for fair competition that no overhead, operation and maintenance or other "to go" costs associated with generation be allowed to remain in regulated rates for Distribution Service or in any transition charge. Otherwise, the result would be a cross-subsidy that would allow the generators a basis to underprice generation with resultant anticompetitive effects.

Similarly, it is critical to exclude from the Distribution Company all costs associated with retailing so as not to disadvantage new retailers considering entry or competing with former utility affiliated retailers.

c. Timing

Power Choice is based on an immediate unbundling of rates. It calls for unbundling to be implemented in each company's rate case. (See, Section III.A.2.e -- Orderly Transition). **Power Choice** proposes that at the time of unbundling, and therefore before direct access to generation suppliers begins, all customers' generation service be provided as Basic Service. Thereafter, by January of 1998, customers will be able to choose their retailer or purchase bilaterally from suppliers using unbundled rates for Distribution Service.

3. *Seek near-term rate relief.*

Power Choice is designed to achieve the lowest possible levels of regulated rates in the near term, and to achieve the most fully effective competition in the market for generation and other retail services.

Lower prices will be achieved by instituting sound market structures that will lead to full competition and real customer choice. **Power Choice's** market structures are fully competitive because they combine both spot market and bilateral direct access mechanisms, and completely separate all competitive functions from the regulated Distribution Company. This divestiture of generation and retail functions will lower prices by minimizing barriers to full and fair competition. These competitive structures begin without delay through a comprehensive transition process that proceeds on multiple tracks.

Competition, properly structured, will lower electricity prices because innovation and efficiencies will lower generation costs, high operating costs will force early retirement of some generating plants, and over time, market opportunities will motivate expansion of low-cost generating capacity. In addition, as soon as real-time pricing becomes available to customers and retailers, along with new metering and load management technology, significant cost savings will result by reducing the levels of consumption at peak periods.

Revenue or price caps for distribution will lower Distribution Service rates. The components of **Power Choice** that address incentive ratemaking for Distribution Companies, presented in Sections III.A.7.a and V, will insure a steady stream of modest rate relief. A price cap which builds in efficiency improvements will reduce rates for Distribution Service per unit of sale on a predetermined schedule. The amount of this reduction will be set in the forthcoming rate cases.

Another way in which **Power Choice** reduces overall levels of rates and prices is the use of spot pricing for Basic Service. Spot prices are likely to be equivalent to contract price levels over sufficiently long periods of time. Use of the spot price for Basic Service avoids the feature of some alternative restructuring plans that offer a price guarantee for customers who continue to receive generation service from the incumbent utility. While price guarantees may appear to offer lower prices immediately, price guarantees will produce anticompetitive effects by maintaining a financial relationship between customers of Distribution Companies and the generation or retail affiliates of those companies. This relationship could raise prices over the longer term by restricting competition.

Finally, stranded costs will be mitigated to the maximum possible extent by relying on market valuation of all exiting utility generating assets. It will also assure that any such changes are competitively neutral, so that competitive forces can take full effect at the outset. Any transition charges will also be minimized by eliminating equity returns on outstanding balances and reducing carrying charges to appropriate debt levels, thereby contributing to near term rate relief.

4. *Maintain DSM programs.*

Once customer choice is initiated, retailers and energy service companies can be expected to compete for customers by packaging services. Energy efficiency and management services are expected to be a key component of this competitive retail marketplace.

While the role of efficiency services in this marketplace is evolving, **Power Choice** provides for continuing DSM support by Distribution Companies at existing levels throughout the transition process. Continued DSM will avoid the loss of the industry infrastructure, and will facilitate the packaging of electricity supplies with efficiency measures in the competitive marketplace for energy services.

All programs and subsidized technologies or services will be assessed for their market maturity. The Distribution Companies will continue to fund only those energy efficiency services and products that have not yet reached market maturity, where efficiency opportunities would otherwise be lost. A number of critical efficiency markets will not be adequately served by the competitive market, specifically, lost opportunity (new construction and time dependent equipment replacement), market transformation, public information and education, and research, development and demonstration programs. One of the key goals of these program activities is to move new and emerging technologies to the market. To maximize the benefits and minimize the costs for these programs, coordinated activities will be encouraged on a statewide basis. These efficiency programs will be reviewed on a biennial basis by the Department, based on program plans and impact evaluation results filed by the Distribution Company. This process will be open to public comment and review.

Funding levels for these efficiency programs will be at or above current utility DSM funding levels. These funding levels will be needed to continue on-going and potential new efficiency services. Continued funding at these levels will also minimize any disruptions to the efficiency industry infrastructure.

In addition, distribution system regulation in the DOER Plan provides ongoing incentive regulation to capture the potential of energy efficiency, load management and distributed generation to defer costly upgrades to the distribution system. (See Section V, Incentive Regulation of Distribution Companies.)

5. *Ensure that the transition is orderly and expeditious, and minimizes customer confusion.*

a. Department Procedure

As a matter of regulatory process, industry restructuring will require a three-step process.¹⁵ First, the Department should establish generic rules for restructuring the companies. These rules should address issues applicable to all electric companies including the unbundling and designing of rates, market structure, treatment of DSM programs and low-income customer programs, a methodology for stranded asset valuation, a mechanism for recovery of any stranded costs, incentive regulations for distribution functions, and procedures for serving customers who cannot or do not exercise their right to choose a generation supplier. Those issues should be resolved in the context of a rulemaking; settlements among affected stakeholders on the generic rules during this process may be possible.

Second, once those rules are established, utilities will update their initial restructuring plans, and possibly reach consensus with other stakeholders regarding those plans and associated rates.

Finally, the Department must complete rate cases for each company. Those companies which have obtained settlements will offer them to the Department for review and acceptance; those without settlements will proceed immediately to full scale adjudications. By grouping the utilities into two tiers of cases and allowing the statutory maximum of six months for those cases, DOER believes all cases could be completed by July of 1997.

b. Restructuring Transition Schedule

The transition schedule must be both expeditious and orderly so that market forces can be harnessed to produce customer benefits as soon as possible. The expeditious resolution of all issues will decrease uncertainties among those seeking to participate in this market. Protracted decision-making processes would increase the perceived risks and lead to greater costs and reduced ratepayer benefits.

¹⁵On February 2, 1996, DOER filed a letter with the Department setting forth a detailed procedural proposal for the period February 16, 1996 through the conclusion of rate cases in July of 1997.

However, not all aspects of the electric industry and its regulation are within Department's jurisdiction. For example, implementation of almost any restructuring scheme will require new legislation. In addition, creation of an Independent System Operator and a Power Exchange affect the other New England states and to a substantial degree are under Federal jurisdiction. Thus, not only should industry restructuring proceed expeditiously, but also with the cooperation of all relevant state, regional and Federal authorities. Restructuring in Massachusetts, however, need not be delayed pending action at the Federal level or at other States.

In order to transform the electric industry in an orderly manner, the Department ought to establish a comprehensive restructuring transition schedule. The timetable should expedite the transition to a competitive retail generation market as soon as possible, while providing for coordination with the other New England states and the Federal government.

Section II.B of this filing presents a series of actions that provide a transition to full competition and real customer choice. These actions translate into the following schedule:

Schedule Of Selected Restructuring Transition Milestones

- | | | |
|--------------------|---|---|
| February 16, 1996: | ● | Pursuant to D.P.U. 95-30, three electric utilities and others file restructuring plans and illustrative unbundled rate information. |
| May 15, 1996: | ● | Deadline for filing settlements on generic rules. |
| July, 1996: | ● | Rules and rates for the ISO and Power Exchange are filed with the FERC for approval. |
| July 15, 1996: | ● | Order on generic rules issued by the Department. |

- August 15, 1996: ● Utilities begin to file rate cases for approval of functional unbundling of costs (including changes to the books of account and cost allocation methods), unbundled rates by class, incentive-based rates for regulated functions, interim stranded cost recovery, and rate design. Utilities file rate tariffs pursuant to the Department's restructuring incentive-based rates guidelines.

- December, 1996: ● FERC approves rules and rates for the ISO and Power Exchange.

- January 1, 1997 ● The new ISO takes control of the system, and the power exchange commences operations. Pilots begin.

- July, 1997: ● The Department has issued Orders on all utility rate filings (or has approved settlement agreements). Cost-of-service regulation ends. Basic Service begins.

- January, 1998: ● Direct customer access commences. Utility sales of non-T&D assets commence.

- December, 1999 ● Air emissions reductions achieved for coal and oil-fired power plants.

- December, 2000: ● Utility sales of non-T&D assets completed.
- Utilities file rate cases for approval of new rates reflecting:
 - The second round of incentive-based rates; and
 - Final stranded cost recovery based on sales of non-T&D assets.

- December, 2001: ● Department issues an Order on the second round of incentive-based rates and on final stranded cost recovery.
- New rates go into effect; interim Competition Transition Charge, based on Department Order of 12/31/96, ceases.

According to the above schedule, NEPOOL reform necessary for the establishment of an ISO and Power Exchange is accomplished on a fast-track basis by the beginning of 1997. Direct access commences in January of 1998. Finally, sales of utility generating assets are completed in 2000, and final transition charges based on those sales are in place, after Department review and approval, by 2001.

c. Retail Access Pilot Programs

Pilot projects will contribute to restructuring of the electric power industry by educating utilities and customers and developing information needed for further restructuring. Pilot projects will enable participating customers to have direct experience with additional choice in the purchase of electricity. Utilities will need to educate their customers on unbundled services and rates. Under pilots, other participants will have the opportunity to develop service offerings to customers. Pilots should provide information on a number of topics, including the preferences of different types of customers, and whether customers respond as quickly as expected to pricing changes.

Pilot programs may provide a useful transition to full retail access in the period before all ratemaking and ownership restructuring has been completed. Pending resolution of any institutional obstacles to full restructuring, pilots introduce some of the benefits of full competition while those institutions are being modified. For instance, a number of existing laws and regulations, such as the Massachusetts fuel charge, (M.G.L. Ch. 164, §94G) will require modification. In order for customers to purchase from a variety of suppliers, current transmission rates must be modified. Competitors in the generation market will need access to ancillary services in order to offer full service to customers. Pilot programs should be available to all customer classes to correct for some of these transitional difficulties.

Utilities should propose pilot programs that will be available to 10 percent of each customer class by January of 1997. Pilot programs on this scale will enable the utilities to develop their own competitive skills and a significant number of customers will gain experience with a competitive market.

Pilot projects should not be construed as a way of delaying retail access to all customers. We do not believe that it will take a long period of experimentation to achieve full competition. While we realize that longer experimentation might provide additional information about customer behavior, we do not believe that the value of such information is so vital that it should delay fundamental changes.

d. Public Information and Involvement

As the Department noted in its Order, the transition period must be orderly, expeditious and minimize customer confusion. A comprehensive, coordinated and collaborative public information campaign is needed throughout the transition process. Customers must be made aware of the opportunities and mechanisms for choosing electric services as well as the responsibilities and risks associated with the range of choices available to them in the new market. Both formal and informal consumer information mechanisms will be needed to ensure that consumer education is far-reaching and effective.

Public information during this period must be unbiased and be easily accessed by consumers. DOER agrees with the findings of the collaborative sponsored by the New Hampshire Public Utility Commission (NHPUC) that utilities should not be permitted to subsidize the marketing efforts of their affiliated marketing companies prior to divestiture. This would create an unfair advantage over competing suppliers. Also, there should be no constraints placed on the marketing activities of competing suppliers and service providers.

DOER supports the Department's call for a negotiation process that includes all affected parties to ensure a smooth transition, including representatives of residential, commercial and industrial customers, utilities, independent power producers, power marketers, public interest and environmental organizations and government agencies. To promote a smooth transition, the Department should also establish a collaborative process among these parties, similar to the NHPUC collaborative, to identify the structure, character and pace of public information efforts. Such mechanisms could include development of information materials for general distribution through print and electronic means, informal information sessions at various locations held by staff of the Department and DOER, bill stuffers to be distributed by utilities at regular intervals during the transition period. The collaborative would also develop recommendations for covering the cost of public information activities through the transition period.

DOER recommends that the collaborative be established to begin work following the Department's Order in July of 1996. Department review and approval of collaborative recommendations should be completed no later than July of 1997 in order to ensure that consumers are adequately prepared for the full transition scheduled on January of 1998.

e. Ownership of Generation by Distribution Companies

Generating units will be spun off and divested into separately owned unregulated companies during the years 1998 through 2000, as described in section III.B.1.c. Recognizing that this will be a complex and unfamiliar process, **Power Choice** includes the following elements to ensure that the process is "orderly and expeditious" and avoids "unintended effects:"

- Electric companies will be allowed to put their generating units on the market on any schedule within the 3-year period;
- However, to provide some coordination of sale dates and avoid depressing prices by putting all units on the market at the same time, the utilities will be encouraged to sign up with the Department for time slots in which to accept bids (perhaps calendar quarters), with the sequence of priority for choosing times based on the sequence in which each utility formally agrees to a specific divestiture plan.

While the above procedures will support an orderly transition, "some level of regulatory oversight will be necessary," as noted by the Department (Order at 45). Specifically, the Department will need to assure that, while any electric company continues to own generating units, those units are not allowed to enter into bilateral contracts with retail customers within the territory of the distribution affiliate. This will prevent abuse of vertical market power, while allowing such generating units to:

- sell to the New England Power Exchange as soon as it is formed (expected to be January of 1997, consistent with the schedule recently proposed by NECPUC),¹⁶
- enter into bilateral contracts with customers outside the territory of the distribution affiliate (beginning in January of 1998).

These arrangements strike an acceptable balance between orderliness and expeditiousness in meeting the Department's principle.

¹⁶ Prior to establishment of the exchange, such units could sell to other unaffiliated buyers on a spot market basis, or sell to the distribution affiliate for resale at spot prices to Basic Service customers.

f. Collaboration to Develop Implementation Details

This plan represents a framework for a practical approach to the comprehensive restructuring needed to assure effective markets. In view of the many transition issues that take time to fully resolve, it will be important to begin developing key implementation details without waiting to complete the negotiation and/or adjudication of all outstanding policy issues.

Parties that can agree on the broad structural elements of this plan are encouraged to begin forming work groups to develop work products such as the following:

- The elements of the filing to FERC to establish the ISO and Power Exchange, to be submitted in July, 1996 on the schedule recently set by NECPUC;
- New approaches to encourage energy efficiency and renewables development; and
- Materials and protocols for delivering information to customers that explain the new markets and choices that customers will need to understand, as discussed in Section d. above.

IV. RATE STRUCTURE

DOER will submit detailed comments on the unbundled, illustrative rates and other rate-related information included in each company's restructuring plan as soon as possible after filing by the companies.

V. INCENTIVE REGULATION OF DISTRIBUTION COMPANIES

The Distribution Company will provide Distribution Service to all electric customers in its service territory, and will provide Basic Service for customers which have not nominated an alternative supplier. Under **Power Choice** incentive regulation by the Department is not applied to generation or transmission except as discussed in section III.A.7.

This section presents in turn each of the following three steps which constitute the price methodology:

First, an annual revenue or price cap per customer class must be determined.

Second, the rate design for each customer class must be established based on each class' annual cap.

Third, a total company rate-of-return bandwidth must be established, including rules for determining profit/loss sharing and trigger points.

A. Formula for Annual Caps Per Customer Class

The retail revenue or price cap per customer class would be determined through the following incentive formula:

$$\begin{aligned} \text{Annual Cap} = & (\text{Adjusted Cost of Service for Distribution Service} \\ & \times \text{Quality/Reliability Index}) \\ & + \text{Distribution Losses Index} \\ & + \text{Low-Income Customer Support Allocation} \\ & + \text{Research \& Development Adjustment} \\ & + \text{Miscellaneous Adjustments}^{17}. \end{aligned}$$

¹⁷ This would include mandated costs outside of utility management control such as tax and accounting changes, extraordinary costs, costs imposed by unanticipated statutory or regulatory change.

1. Adjusted Cost of Service for Distribution Service

Initially, the "Adjusted Cost of Service" would be based upon the embedded and marginal cost of Distribution Service as determined by the Department in a rate proceeding. These cost levels are the primary determinant in the incentive formula for the level of the rates at the outset of the period.

The embedded cost of service would include the costs associated with existing distribution investment¹⁸ (e.g., depreciation, return, taxes, etc.), and Distribution Company administrative and general expenses incurred to support the distribution function. Over the period in which the revenue cap is in effect, the expense portion of annual embedded costs may increase as a function of inflation. The annual rate of depreciation and inflation would be accounted for in the revenue cap formulas at the time such formulas are approved. If the number of customers or loads are anticipated to increase in the future, or if existing T&D equipment is retired (because of age or poor reliability) and must be replaced with new equipment, the Distribution Company would incur additional costs in the future. The revenue caps would be adjusted to account for such additional costs.

The marginal cost of service would be based on the avoidable costs of distribution investments at the outset of the cap period, with appropriate adders for administrative and general costs. To the extent that the marginal cost of new distribution resources are reduced during the period in which the cap is in effect, through distributed generation or other new technology, the Distribution Company would retain the difference between the revenues originally set and the lower cost of the new technology.

Over time, the cost index must be adjusted downward by a productivity factor, which is incorporated into the revenue cap formulas at the time they are initially approved, so that cost savings achieved by Distribution Companies are shared with customers. The productivity factor is the key to guaranteeing customers that, during the term of the cap, rates for Distribution Service will be "meaningfully lower than they would have been under the current system of rate regulation," in accordance with the Department principle "seek near-term rate relief" (Order, at 44).

¹⁸ Interstate transmission costs subject to Federal jurisdiction would be based on FERC-approved transmission tariffs.

In view of the importance of rate relief, this productivity factor should be benchmarked to the performance of other companies (with comparable distribution system conditions) in reducing their distribution or wheeling rates over a similar time period. This benchmarking will introduce an additional element of cost-cutting pressure from indirect competition between Distribution Companies. In addition, for any Distribution Company with a distribution revenue level that is significantly above the revenue levels of comparable distribution systems, the productivity factor should be set in such a way that it penalizes such companies and provides additional rate relief to their customers at the outset of the cap period as well as during each subsequent year that such high costs persist.

2. Quality and Reliability Performance Index

To discourage Distribution Companies from minimizing costs at the expense of customer service quality and reliability, the price formula should be indexed to a measure of customer service quality and reliability. Broad measures of customer service quality and reliability should be used such as annual customer satisfaction surveys and the number of distribution-related outages (including the amount of load and number of customers disconnected and the number of outage hours). Extraordinary events outside of the Distribution Company's control (e.g., hurricanes) would be excluded from the calculation. The customer service quality and reliability factors and the methods of measurement would be determined at each general rate proceeding. Such factors would be used to adjust the revenue cap formula for the following year. Surveys on Distribution Company service quality would be conducted annually by an independent expert.

3. Distribution Losses Index

The index could be called the "Adjusted Cost of Energy Index from Distribution Losses." It is used to give Distribution Companies the incentive to cost-effectively reduce distribution losses. The difference between the metered electricity at the transmission delivery point and the aggregate loads at customer meters on the distribution system would define distribution losses. This difference should be the responsibility of the Distribution Company. The Index could be initially set at the average Company loss levels times the average spot market prices. Using an annual productivity factor adjustment which lowers the Index over time, Companies are given the incentive to find ways to reduce the cost that such losses impose.

4. Low-Income Customer Support Allocation

Support to low-income customers would be subsidized through the revenue caps of other customer classes. The allocation of the subsidy to specific customer classes could be based on the same methods as those presently used by the Department. Since low-income support is a cost reallocation mechanism, no particular performance review or adjustment is required.

5. Research & Development Adjustment

DOER's energy policy objectives call for the research and development of commercially promising technologies, including renewable and energy efficiency technologies appropriate for distribution-level applications. Thus, the revenue cap formula should include a factor to support Distribution Company activities that are consistent with this policy. The level of revenue devoted to such activities would be approved by the Department at the time revenue cap formulas are determined. The Distribution Company's activities in this area would be reviewed at the same time customer service quality and reliability is reviewed.

B. Rate Design

In the rate design phase, the rates paid by retail customers ought to reflect marginal costs by function (i.e., unbundled marginal cost rates by function) to the extent possible consistent with the class revenue cap. Two-block rate designs could be used to accomplish this objective, where the initial-block reflects embedded costs and customer costs, and the tail-block reflects marginal costs. Rate designs could be derived directly from embedded and marginal cost information used to form class-specific retail revenue caps (i.e., customer and demand charges unbundled by function). However, specific customer class rate designs may be driven by constraints such as cost-effective metering capability. For example, small-use customers may still be charged on a customer and energy charge basis for transmission and distribution functions to the extent that time-of-use metering is not cost-effective. Thus, class rates designed to collect revenues up to the revenue cap must be reconciled to metered consumption on some reasonable basis.

Individual customer class rate designs would be determined on a case-by-case basis and would be subject to Department approval. In determining appropriate rate designs, the Department must balance various pricing objectives including economic efficiency, rate continuity, fairness, Distribution Company earnings stability, and simplicity. We would anticipate that rates to Distribution Company customers would be primarily designed to recover allowable revenue requirements pursuant to the class revenue cap formulas.

Customers within the same rate class should be charged similar rates for Distribution Company services. However, rate credits to consumers providing benefits to the Distribution Company (e.g., peak load management) should vary by local planning area depending on area-specific marginal T&D costs. Such rate credits should be used to provide the correct price signals to consumers or their competitive suppliers that are in a position to invest in distributed generation, load management or efficiency resources which the Distribution Company will seek in response to the incentive to cut the costs of Distribution Service.

C. Rate-of-Return Bandwidth

The third step in this pricing methodology utilizes rate-of-return bandwidths to determine when the Distribution Company is earning exorbitant or confiscatory returns on net capital invested in State-regulated transmission, distribution and customer service functions. Using methodologies similar to those presently being employed to set cost-of-service rates, a benchmark return on invested capital for each individual Distribution Company would be established. The benchmark return could also be indexed so that changes in financial market conditions could be taken into account when determining benchmark returns in future periods.

After establishing the benchmark return, a "dead-band" around the benchmark return must be determined. This bandwidth should be wide and symmetrical around the benchmark return (e.g., 200 to 600 basis points or more above and below the benchmark return). Distribution Companies would be allowed to earn returns within this dead-band without sharing them with customers or triggering regulatory intervention.

Returns outside this dead-band, but within a "profit-sharing band," would trigger a sharing of profits or losses with customers. For example, the price formula could provide that 50 percent of the excess or deficient revenues for returns above or below the dead-band, (but within the profit-sharing band), from any given year could be subtracted from or added to the retail revenue caps in the following year. Such profit/loss sharing mechanisms should be established on a case-by-case basis as warranted by individual utility circumstances.

Returns outside this profit-sharing band would require a general revenue cap rate review. Otherwise, rates would not be investigated by the Department.

D. Implementation Plan

The incentive regulation approach outlined here should be specified by the Department in its generic rules, and applied to the rates for Distribution Service in all the Distribution Companies' rate cases, which are to be completed by July of 1997. (See Section II.B on the transition process.)

The incentive-based distribution rates should be in effect for approximately five years from the conclusion of each company's rate case in 1997 through 2001. By the end of this period, generation asset sales or spin-offs will have been completed (the specified deadline is December of 2000). At that time, another set of rate cases should be undertaken. The transition charge will be adjusted as necessary to reflect the market valuation of stranded costs, and the desired strategy for rate levels and stranded cost recovery over the remaining years of the ten-year stranded cost transition period.

Thereafter, we recommend that incentive-based rate formulas be reviewed and established once every five years and that performance reviews of Distribution Company rates of return (pursuant to the rate-of-return bandwidth) and of targeted incentives (e.g., customer service, research and development) be conducted every one or two years.

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Appendix A

PARTICIPANTS IN A RESTRUCTURED ELECTRIC INDUSTRY

A restructured electric industry will be an evolving marketplace with a variety of participants. These participants will be differentiated by whether they operate at the wholesale or retail level and by whether they are regulated or unregulated entities. The table below identifies some, though not all, of the key likely participants.

PARTICIPANTS in a RESTRUCTURED ELECTRIC INDUSTRY

	REGULATED	COMPETITIVE
WHOLESALE	Independent System Operator Power Exchange	Generators Marketers Brokers Spot and Futures Markets
RETAIL	Distribution Companies	Retailers Load Aggregators Energy Service Companies

The Regulated Wholesale Market

Power Exchange (PX) The PX will be a separate, independent entity which will maintain a voluntary spot market, determine the market price for electricity and clear any financial imbalances between buyers and sellers. The PX will make the market clearing spot price available on an open, transparent basis, but will maintain the confidentiality of individual price bids. It will offer some ancillary balancing and services to the ISO and settle transactions among the ISO and other players who use the spot market. Its focus will be the economic aspects of short term transactions in the regional competitive generation market. The establishment and operation of the PX would likely be subject to FERC jurisdiction, but there would be no price regulation per se.

Independent System Operator (ISO) The ISO will be a new, regional entity formed to support efficient and fair competition in the wholesale market by insuring that the operation of the high voltage transmission system is independent of ownership of power plants and transmission facilities. Functionally, it replaces NEPOOL transmission and reliability functions with new rules or protocols approved by FERC. Its focus will be ensuring reliability and fair, open access in a competitive market. Currently all transmission facilities are owned and maintained by vertically integrated Utilities. The proposed restructuring plan calls for these owners to lease these facilities to the ISO so that the ISO may operate the System without regard to ownership of these assets. Transmission pricing and lease compensation will be regulated by FERC.

The Competitive Wholesale Market

Generators Generators will own and operate all types of existing and new power plants on an unregulated basis (with respect to price). Generators may sell energy, capacity, voltage regulation, frequency control, reactive power and operating reserves subject to the protocols of the ISO and (if they wish) the PX. They may contract directly (bilaterally) with marketers, retailers or high voltage customers under any terms mutually agreed upon, and are financially at risk for performance of those contracts. They may also buy and sell in the spot market through the PX or through other providers of spot market services, and may take positions in the Futures Market. Their success depends upon their efficacy in operating their power plants and managing their price risk.

Spot and Futures Markets These markets are exchanges for buyers and sellers of electricity. They will enable players to balance supply and demand. Spot market(s) will determine the current price of electricity which balances supply and demand. Futures market(s) will allow players to obtain risk management of their longer term electricity transactions.

Initially there will be a voluntary spot market maintained by the PX and regulated by FERC, but other spot markets may develop. In the spot market, sellers offer their generation for energy and reserves for the immediately forthcoming period be it a day, hour, half hour or instantaneously. The last offer accepted establishes that period's price for electricity which will be used in many transactions to balance accounts.

The futures market(s) will be maintained by regulated commodity exchange(s). Buyers, sellers or traders use futures contracts traded in the futures market to manage price and supply risk.

Marketers Marketers buy and sell, but do not produce, high voltage electricity. They will work with various generators as well as represent themselves in these transactions. Marketers will take title to the electricity. Electricity will likely be only one of many forms of energy offered for sale by marketers. A marketer may or may not arrange for electricity delivery through the Distribution Company. Marketers can include arrangements for transmission, ancillary services and financial risk management. Marketers can deal in both short and long term contracts, bilateral contracts as well as related services and will be financially at risk for their contracts. Marketers currently operate in other competitive energy markets and succeed or fail based on their ability to obtain favorable terms for their transactions and their ability to manage contractual risk.

Brokers Brokers match buyers and sellers for short and/or long term energy supply. Brokers do not take title to the electricity, and thus the contracting buyers and sellers will be financially at risk for their contracts. Brokers may arrange delivery, financial risk management and other services.

The Regulated Retail Market

The Distribution Companies The Distribution Companies will play a critical role in providing Distribution Service and other essential monopoly services to the competitive market. They will provide generators and retailers access to all customers not served directly from the transmission system. The Distribution Companies will be separate from and unaffiliated with any particular generator or retailer. Distribution Companies will be prohibited from competition with retailers because the Distribution Companies could exert undue and unfair influence on customers, on pricing, and on access to and use of their regulated functions. Distribution Companies will treat all retailers equitably so the latter can compete fairly for customers. The Distribution Company will have the responsibility to provide central settlement, reconciliation and balancing for all retailers' and all customers' accounts.

The Distribution Companies providing Distribution Service will be restricted to *wires* function and spot-priced Basic Service (for customers that do not choose, and for peaking and supplemental supply). The obligation to serve will be replaced with the obligation to connect and provider of last resort. The Distribution Companies will also collect any Transition charge. Distribution Companies will administer the continuation of low income and shut off protections.

The Competitive Retail Market

Retailers Retailers will compete to sell electricity to customers. They may sell electricity only, or they may market the electricity together with other services such as energy efficiency and/or load management as well as other forms of energy and related services. They will compete on the basis of price and services. Customer attraction, retention and satisfaction are expected to be key determinants of business success along with the price, variety and delivery of services. The dynamics of the marketplace will determine what forms of pricing and services best meet customers' needs and which retailers succeed. In addition to competing for customers, retailers purchase electricity from generators or through brokers. Generators will not be prohibited from entering the retail supply business; thus retailers may also be generators. Retailers and generators are responsible for arranging and paying for the transmission of electricity to the Distribution Company of the customer (unless the customer elects to pay for such transmission directly). The retailers and the Distribution Companies are responsible for their commercial transaction to deliver, meter, bill and collect payment from the customer. Retailers, while not price regulated, will be certified by the Department to conduct business in the Commonwealth in order to insure that basic consumer interests are protected.

Load Aggregators Customers will be free to contract with any certified retailer, and will also be free to form buyers' cooperatives or associations to act on their behalf, or to contract with load aggregators to obtain their electricity services. Load aggregators will be municipal or private entities which organize customers in order to obtain more favorable contracts from retailers or marketers. Load aggregators will be agents who specialize in bringing buyers together. They will generally not take title to the electricity but instead provide the service of arranging multiple customer purchases. They may also arrange for additional services, such as negotiating contract terms with retailers and energy service companies for their clients. Municipal load aggregators could provide the load aggregation service for all interested residents but would not restrict the right to contract directly.

Energy Service Companies Energy service companies will generally specialize in services related to energy utilization and management. Historically, they have included financing and sharing of energy savings. In the future, the competitive market will determine how these services will be structured. Energy service companies may contract directly with consumers or through retailers, marketers, brokers or load aggregators. Their offerings may include a broad range of energy related services including, generation supply and risk management.

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